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Insulators and Accessories

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Electric insulation is a vital part of an electrical power system. Although the cost of insulation is only a small fraction of the apparatus or line cost, line performance is highly dependent on insulation integrity. Insulation failure may cause permanent equipment damage and long-term outages. As an example, a short circuit in a 500-kV system may result in a loss of power to a large area for several hours. The potential financial losses emphasize the importance of a reliable design of the insulation.

The insulation of an electric system is divided into two broad categories:

1. Internal insulation
2. External insulation

Apparatus or equipment has mostly internal insulation. The insulation is enclosed in a grounded housing which protects it from the environment. External insulation is exposed to the environment. A typical example of internal insulation is the insulation for a large transformer where insulation between turns and between coils consists of solid (paper) and liquid (oil) insulation protected by a steel tank. An overvoltage can produce internal insulation breakdown and a permanent fault.

External insulation is exposed to the environment. Typical external insulation is the porcelain insulators supporting transmission line conductors. An overvoltage caused by flashover produces only a temporary fault. The insulation is self-restoring.

This section discusses external insulation used for transmission lines and substations.

10.1 Electrical Stresses on External Insulation

The external insulation (transmission line or substation) is exposed to electrical, mechanical, and environmental stresses. The applied voltage of an operating power system produces electrical stresses. The weather and the surroundings (industry, rural dust, oceans, etc.) produce additional environmental

stresses. The conductor weight, wind, and ice can generate mechanical stresses. The insulators must withstand these stresses for long periods of time. It is anticipated that a line or substation will operate for more than 20–30 years without changing the insulators. However, regular maintenance is needed to minimize the number of faults per year. A typical number of insulation failure-caused faults is 0.5–10 per year, per 100 mi of line.

10.1.1 Transmission Lines and Substations

Transmission line and substation insulation integrity is one of the most dominant factors in power system reliability. We will describe typical transmission lines and substations to demonstrate the basic concept of external insulation application.

Figure 10.1 shows a high-voltage transmission line. The major components of the line are:

1. Conductors
2. Insulators
3. Support structure tower

The insulators are attached to the tower and support the conductors. In a suspension tower, the insulators are in a vertical position or in a V-arrangement. In a dead-end tower, the insulators are in a horizontal position. The typical transmission line is divided into sections and two dead-end towers terminate each section. Between 6 and 15 suspension towers are installed between the two dead-end towers. This sectionalizing prevents the propagation of a catastrophic mechanical fault beyond each section. As an example, a tornado caused collapse of one or two towers could create a domino effect, resulting in the collapse of many miles of towers, if there are no dead ends.



FIGURE 10.1 A 500-kV suspension tower with V string insulators.

Figure 10.2 shows a lower voltage line with post-type insulators. The rigid, slanted insulator supports the conductor. A high-voltage substation may use both suspension and post-type insulators. References [1,2] give a comprehensive description of transmission lines and discuss design problems.

10.1.2 Electrical Stresses

The electrical stresses on insulation are created by:

1. Continuous power frequency voltages
2. Temporary overvoltages
3. Switching overvoltages
4. Lightning overvoltages

10.1.2.1 Continuous Power Frequency Voltages

The insulation has to withstand normal operating voltages. The operating voltage fluctuates from changing load. The normal range of fluctuation is around $\pm 10\%$. The line-to-ground voltage causes the voltage stress on the insulators. As an example, the insulation requirement of a 220-kV line is at least:

$$1.1 \times \frac{220 \text{ kV}}{\sqrt{3}} \cong 140 \text{ kV} \quad (10.1)$$

This voltage is used for the selection of the number of insulators when the line is designed. The insulation can be laboratory tested by measuring the dry flashover voltage of the insulators. Because the line insulators are self-restoring, flashover tests do not



FIGURE 10.2 69-kV transmission line with post insulators.

cause any damage. The flashover voltage must be larger than the operating voltage to avoid outages. For a porcelain insulator, the required dry flashover voltage is about 2.5–3 times the rated voltage. A significant number of the apparatus standards recommend dry withstand testing of every kind of insulation to be two (2) times the rated voltage plus 1 kV for 1 min of time. This severe test eliminates most of the deficient units.

10.1.2.2 Temporary Overvoltages

These include ground faults, switching, load rejection, line energization and resonance, cause power frequency, or close-to-power frequency, and relatively long duration overvoltages. The duration is from 5 sec to several minutes. The expected peak amplitudes and duration are listed in Table 10.1.

The base is the crest value of the rated voltage. The dry withstand test, with two times the maximum operating voltage plus 1 kV for 1 minute, is well-suited to test the performance of insulation under temporary overvoltages.

10.1.2.3 Switching Overvoltages

The opening and closing of circuit breakers causes switching overvoltages. The most frequent causes of switching overvoltages are fault or ground fault clearing, line energization, load interruption, interruption of inductive current, and switching of capacitors.

Switching produces unidirectional or oscillatory impulses with durations of 5000–20,000 μ sec. The amplitude of the overvoltage varies between 1.8 and 2.5 per unit. Some modern circuit breakers use pre-insertion resistance, which reduces the overvoltage amplitude to 1.5–1.8 per unit. The base is the crest value of the rated voltage.

Switching overvoltages are calculated from computer simulations that can provide the distribution and standard deviation of the switching overvoltages. Figure 10.3 shows typical switching impulse voltages. Switching surge performance of the insulators is determined by flashover tests. The test is performed by applying a standard impulse with a time to crest of 250 μ sec and time to half value of

TABLE 10.1 Expected Amplitude of Temporary Overvoltages

Type of Overvoltage	Expected Amplitude	Duration
Fault overvoltages		
Effectively grounded	1.3 per unit	1 sec
Resonant grounded	1.73 per unit or greater	10 sec
Load rejection		
System substation	1.2 per unit	1–5 sec
Generator station	1.5 per unit	3 sec
Resonance	3 per unit	2–5 min
Transformer energization	1.5–2.0 per unit	1–20 sec

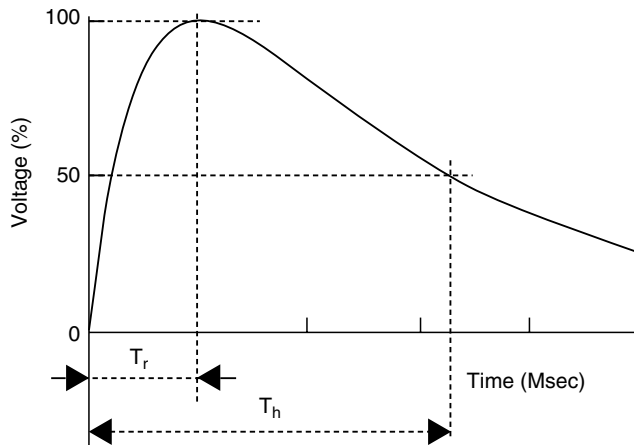


FIGURE 10.3 Switching overvoltages. $T_r = 20\text{--}5000\ \mu\text{sec}$, $T_h < 20,000\ \mu\text{sec}$, where T_r is the time-to-crest value and T_h is the time-to-half value.

5000 μsec . The test is repeated 20 times at different voltage levels and the number of flashovers is counted at each voltage level. These represent the statistical distribution of the switching surge impulse flashover probability. The correlation of the flashover probability with the calculated switching impulse voltage distribution gives the probability, or risk, of failure. The measure of the risk of failure is the number of flashovers expected by switching surges per year.

10.1.2.4 Lightning Overvoltages

Lightning overvoltages are caused by lightning strikes:

1. to the phase conductors
2. to the shield conductor (the large current-caused voltage drop in the grounding resistance may cause flashover to the conductors [back flash]).
3. to the ground close to the line (the large ground current induces voltages in the phase conductors).

Lightning strikes cause a fast-rising, short-duration, unidirectional voltage pulse. The time-to-crest is between 0.1–20 μsec . The time-to-half value is 20–200 μsec .

The peak amplitude of the overvoltage generated by a direct strike to the conductor is very high and is practically limited by the subsequent flashover of the insulation. Shielding failures and induced voltages cause somewhat less overvoltage. Shielding failure caused overvoltage is around 500 kV–2000 kV. The lightning-induced voltage is generally less than 400 kV. The actual stress on the insulators is equal to the impulse voltage.

The insulator BIL is determined by using standard lightning impulses with a time-to-crest value of 1.2 μsec and time-to-half value of 50 μsec . This is a measure of the insulation strength for lightning. [Figure 10.4](#) shows a typical lightning pulse.

When an insulator is tested, peak voltage of the pulse is increased until the first flashover occurs. Starting from this voltage, the test is repeated 20 times at different voltage levels and the number of flashovers are counted at each voltage level. This provides the statistical distribution of the lightning impulse flashover probability of the tested insulator.

10.1.3 Environmental Stresses

Most environmental stress is caused by weather and by the surrounding environment, such as industry, sea, or dust in rural areas. The environmental stresses affect both mechanical and electrical performance of the line.

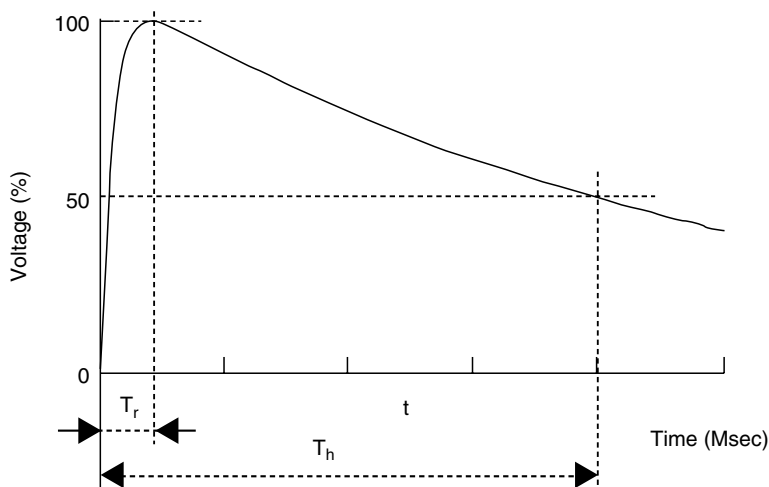


FIGURE 10.4 Lightning overvoltages. $T_r = 0.1\text{--}20\ \mu\text{sec}$, $T_h = 20\text{--}200\ \mu\text{sec}$, where T_r is the time-to-crest value and T_h is the time-to-half value.

10.1.3.1 Temperature

The temperature in an outdoor station or line may fluctuate between -50°C and $+50^\circ\text{C}$, depending upon the climate. The temperature change has no effect on the electrical performance of outdoor insulation. It is believed that high temperatures may accelerate aging. Temperature fluctuation causes an increase of mechanical stresses, however it is negligible when well-designed insulators are used.

10.1.3.2 UV Radiation

UV radiation accelerates the aging of nonceramic composite insulators, but has no effect on porcelain and glass insulators. Manufacturers use fillers and modified chemical structures of the insulating material to minimize the UV sensitivity.

10.1.3.3 Rain

Rain wets porcelain insulator surfaces and produces a thin conducting layer most of the time. This reduces the flashover voltage of the insulators. As an example, a 230-kV line may use an insulator string with 12 standard ball-and-socket-type insulators. Dry flashover voltage of this string is 665 kV and the wet flashover voltage is 502 kV. The percentage reduction is about 25%.

Nonceramic polymer insulators have a water-repellent hydrophobic surface that reduces the effects of rain. As an example, with a 230-kV composite insulator, dry flashover voltage is 735 kV and wet flashover voltage is 630 kV. The percentage reduction is about 15%. The insulator's wet flashover voltage must be higher than the maximum temporary overvoltage.

10.1.3.4 Icing

In industrialized areas, conducting water may form ice due to water-dissolved industrial pollution. An example is the ice formed from acid rain water. Ice deposits form bridges across the gaps in an insulator string that result in a solid surface. When the sun melts the ice, a conducting water layer will bridge the insulator and cause flashover at low voltages. Melting ice-caused flashover has been reported in the Quebec and Montreal areas.

10.1.3.5 Pollution

Wind drives contaminant particles into insulators. Insulators produce turbulence in airflow, which results in the deposition of particles on their surfaces. The continuous depositing of the particles increases the thickness of these deposits. However, the natural cleaning effect of wind, which blows

TABLE 10.2 Site Severity (IEEE Definitions)

Description	ESDD (mg/cm ²)
Very light	0–0.03
Light	0.03–0.06
Moderate	0.06–0.1
Heavy	<0.1

loose particles away, limits the growth of deposits. Occasionally, rain washes part of the pollution away. The continuous depositing and cleaning produces a seasonal variation of the pollution on the insulator surfaces. However, after a long time (months, years), the deposits are stabilized and a thin layer of solid deposit will cover the insulator. Because of the cleaning effects of rain, deposits are lighter on the top of the insulators and heavier on the bottom. The development of a continuous pollution layer is compounded by chemical changes. As an example, in the vicinity of a cement factory, the interaction between the cement and water produces a tough, very sticky layer. Around highways, the wear of car tires produces a slick, tar-like carbon deposit on the insulator's surface.

Moisture, fog, and dew wet the pollution layer, dissolve the salt, and produce a conducting layer, which in turn reduces the flashover voltage. The pollution can reduce the flashover voltage of a standard insulator string by about 20–25%.

Near the ocean, wind drives salt water onto insulator surfaces, forming a conducting salt-water layer which reduces the flashover voltage. The sun dries the pollution during the day and forms a white salt layer. This layer is washed off even by light rain and produces a wide fluctuation in pollution levels.

The Equivalent Salt Deposit Density (ESDD) describes the level of contamination in an area. Equivalent Salt Deposit Density is measured by periodically washing down the pollution from selected insulators using distilled water. The resistivity of the water is measured and the amount of salt that produces the same resistivity is calculated. The obtained mg value of salt is divided by the surface area of the insulator. This number is the ESDD. The pollution severity of a site is described by the average ESDD value, which is determined by several measurements.

Table 10.2 shows the criteria for defining site severity.

The contamination level is light or very light in most parts of the U.S. and Canada. Only the seashores and heavily industrialized regions experience heavy pollution. Typically, the pollution level is very high in Florida and on the southern coast of California. Heavy industrial pollution occurs in the industrialized areas and near large highways. Table 10.3 gives a summary of the different sources of pollution.

The flashover voltage of polluted insulators has been measured in laboratories. The correlation between the laboratory results and field experience is weak. The test results provide guidance, but insulators are selected using practical experience.

TABLE 10.3 Typical Sources of Pollution

Pollution Type	Source of Pollutant	Deposit Characteristics	Area
Rural areas	Soil dust	High resistivity layer, effective rain washing	Large areas
Desert	Sand	Low resistivity	Large areas
Coastal area	Sea salt	Very low resistivity, easily washed by rain	10–20 km from the sea
Industrial	Steel mill, coke plants, chemical plants, generating stations, quarries	High conductivity, extremely difficult to remove, insoluble	Localized to the plant area
Mixed	Industry, highway, desert	Very adhesive, medium resistivity	Localized to the plant area

10.1.3.6 Altitude

The insulator's flashover voltage is reduced as altitude increases. Above 1500 feet, an increase in the number of insulators should be considered. A practical rule is a 3% increase of clearance or insulator strings' length per 1000 ft as the elevation increases.

10.1.4 Mechanical Stresses

Suspension insulators need to carry the weight of the conductors and the weight of occasional ice and wind loading.

In northern areas and in higher elevations, insulators and lines are frequently covered by ice in the winter. The ice produces significant mechanical loads on the conductor and on the insulators. The transmission line insulators need to support the conductor's weight and the weight of the ice in the adjacent spans. This may increase the mechanical load by 20–50%.

The wind produces a horizontal force on the line conductors. This horizontal force increases the mechanical load on the line. The wind-force-produced load has to be added vectorially to the weight-produced forces. The design load will be the larger of the combined wind and weight, or ice and wind load.

The dead-end insulators must withstand the longitudinal load, which is higher than the simple weight of the conductor in the half span.

A sudden drop in the ice load from the conductor produces large-amplitude mechanical oscillations, which cause periodic oscillatory insulator loading (stress changes from tension to compression and back).

The insulator's one-minute tension strength is measured and used for insulator selection. In addition, each cap-and-pin or ball-and-socket insulator is loaded mechanically for one minute and simultaneously energized. This mechanical and electrical (M&E) value indicates the quality of insulators. The maximum load should be around 50% of the M&E load.

The Bonneville Power Administration uses the following practical relation to determine the required M&E rating of the insulators.

1. $M\&E > 5 \times \text{Bare conductor weight/span}$
2. $M\&E > \text{Bare conductor weight} + \text{Weight of 3.81 cm (1.5 in) of ice on the conductor (3 lb/sq ft)}$
3. $M\&E > 2 \times (\text{Bare conductor weight} + \text{Weight of 0.63 cm (1/4 in) of ice on the conductor and loading from a wind of 1.8 kg/sq ft (4 lb/sq ft)})$

The required M&E value is calculated from all equations above and the largest value is used.

10.2 Ceramic (Porcelain and Glass) Insulators

10.2.1 Materials

Porcelain is the most frequently used material for insulators. Insulators are made of wet, processed porcelain. The fundamental materials used are a mixture of feldspar (35%), china clay (28%), flint (25%), ball clay (10%), and talc (2%). The ingredients are mixed with water. The resulting mixture has the consistency of putty or paste and is pressed into a mold to form a shell of the desired shape. The alternative method is formation by extrusion bars that are machined into the desired shape. The shells are dried and dipped into a glaze material. After glazing, the shells are fired in a kiln at about 1200°C. The glaze improves the mechanical strength and provides a smooth, shiny surface. After a cooling-down period, metal fittings are attached to the porcelain with Portland cement. Reference [3] presents the history of porcelain insulators and discusses the manufacturing procedure.

Toughened glass is also frequently used for insulators [4]. The melted glass is poured into a mold to form the shell. Dipping into hot and cold baths cools the shells. This thermal treatment shrinks the surface of the glass and produces pressure on the body, which increases the mechanical strength of the glass. Sudden mechanical stresses, such as a blow by a hammer or bullets, will break the glass into small pieces. The metal end-fitting is attached by alumina cement.

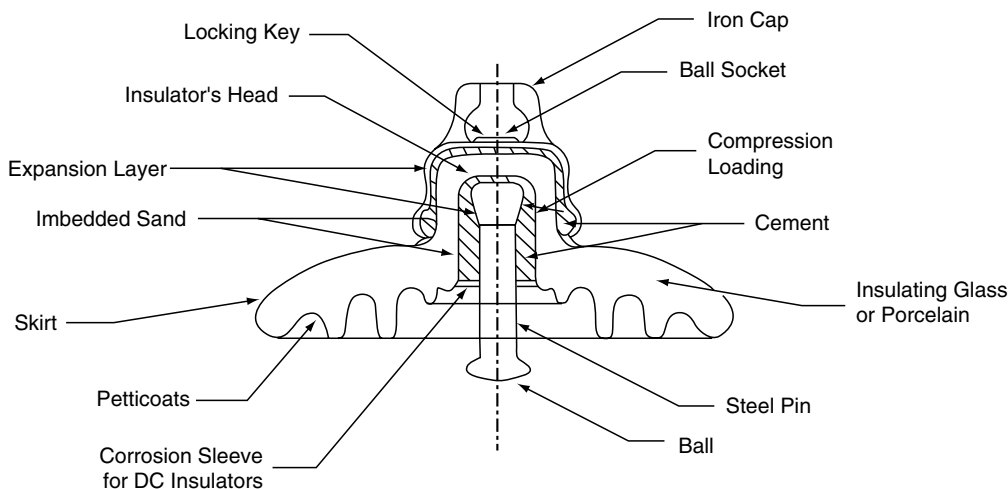


FIGURE 10.5 Cross-section of a standard ball-and-socket insulator.

10.2.2 Insulator Strings

Most high-voltage lines use ball-and-socket-type porcelain or toughened glass insulators. These are also referred to as “cap and pin.” The cross section of a ball-and-socket-type insulator is shown in Fig. 10.5.

Table 10.4 shows the basic technical data of these insulators.

The porcelain skirt provides insulation between the iron cap and steel pin. The upper part of the porcelain is smooth to promote rain washing and cleaning of the surface. The lower part is corrugated, which prevents wetting and provides a longer protected leakage path. Portland cement attaches the cup and pin. Before the application of the cement, the porcelain is sandblasted to generate a rough surface. A thin expansion layer (e.g., bitumen) covers the metal surfaces. The loading compresses the cement and provides high mechanical strength.

The metal parts of the standard ball-and-socket insulator are designed to fail before the porcelain fails as the mechanical load increases. This acts as a mechanical fuse protecting the tower structure.

The ball-and-socket insulators are attached to each other by inserting the ball in the socket and securing the connection with a locking key. Several insulators are connected together to form an insulator string. Figure 10.6 shows a ball-and-socket insulator string and the clevis-type string, which is used less frequently for transmission lines.

Fog-type, long leakage distance insulators are used in polluted areas, close to the ocean, or in industrial environments. Figure 10.7 shows representative fog-type insulators, the mechanical strength of which is higher than standard insulator strength. As an example, a $6\frac{1}{2} \times 12\frac{1}{2}$ fog-type insulator is rated to 180 kN (40 klb) and has a leakage distance of 50.1 cm (20 in.).

Insulator strings are used for high-voltage transmission lines and substations. They are arranged vertically on support towers and horizontally on dead-end towers. Table 10.5 shows the typical number of insulators used by utilities in the U.S. and Canada in lightly polluted areas.

TABLE 10.4 Technical Data of a Standard Insulator

Diameter	25.4 cm	(10 in.)
Spacing	14.6 cm	(5-3/4 in.)
Leakage distance	305 cm	(12 ft)
Typical operating voltage	10 kV	
Mechanical strength	75 kN	(15 klb)

10.2.3 Post-Type Insulators

Post-type insulators are used for medium- and low-voltage transmission lines, where insulators replace the cross-arm (Fig. 10.3). However, the majority of post insulators are used in substations where insulators support conductors, bus bars, and

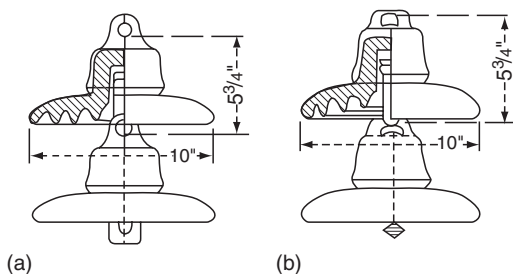


FIGURE 10.6 Insulator string: (a) clevis type, (b) ball-and-socket type.

equipment. A typical example is the interruption chamber of a live tank circuit breaker. Typical post-type insulators are shown in Fig. 10.8.

Older post insulators are built somewhat similar to cap-and-pin insulators, but with hardware that permits stacking of the insulators to form a high-voltage unit. These units can be found in older stations. Modern post insulators consist of a porcelain column, with weather skirts or corrugation on the outside surface to increase leakage distance. For indoor use, the outer surface is corru-

gated. For outdoor use, a deeper weather shed is used. The end-fitting seals the inner part of the tube to prevent water penetration. Figure 10.8 shows a representative unit used at a substation. Equipment manufacturers use the large post-type insulators to house capacitors, fiber-optic cables and electronics, current transformers, and operating mechanisms. In some cases, the insulator itself rotates and operates disconnect switches.

Post insulators are designed to carry large compression loads, smaller bending loads, and small tension stresses.

10.2.4 Long Rod Insulators

The long rod insulator is a porcelain rod with an outside weather shed and metal end fittings. The long rod is designed for tension load and is applied on transmission lines in Europe. Figure 10.9 shows a typical long rod insulator. These insulators are not used in the U.S. because vandals may shoot the insulators, which will break and cause outages. The main advantage of the long rod design is the elimination of metal parts between the units, which reduces the insulator's length.

10.3 Nonceramic (Composite) Insulators

Nonceramic insulators use polymers instead of porcelain. High-voltage composite insulators are built with mechanical load-bearing fiberglass rods, which are covered by polymer weather sheds to assure high electrical strength.

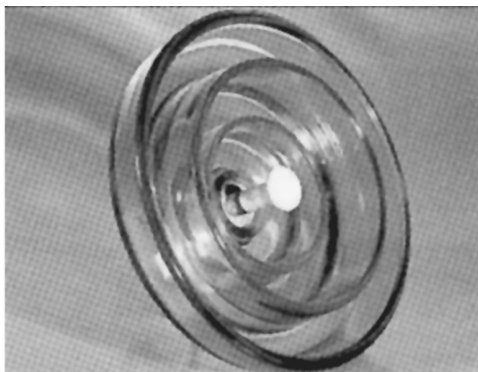


FIGURE 10.7 Standard and fog-type insulators. (Courtesy of Sediver, Inc., Nanterre Cedex, France.)

TABLE 10.5 Typical Number of Standard (5-1/4 ft × 10 in.) Insulators at Different Voltage Levels

Line Voltage (kV)	Number of Standard Insulators
69	4–6
115	7–9
138	8–10
230	12
287	15
345	18
500	24
765	30–35

The first insulators were built with bisphenol epoxy resin in the mid-1940s and are still used in indoor applications. Cycloaliphatic epoxy resin insulators were introduced in 1957. Rods with weather sheds were molded and cured to form solid insulators. These insulators were tested and used in England for several years. Most of them were exposed to harsh environmental stresses and failed. However, they have been successfully used indoors. The first composite insulators, with fiberglass rods and rubber weather sheds, appeared in the mid-1960s. The advantages of these insulators are [5–7]:

- Lightweight, which lowers construction and transportation costs.
- More vandalism resistant.
- Higher strength-to-weight ratio, allowing longer design spans.
- Better contamination performance.
- Improved transmission line aesthetics, resulting in better public acceptance of a new line.

However, early experiences were discouraging because several failures were observed during operation. Typical failures experienced were:

- Tracking and erosion of the shed material, which led to pollution and caused flashover.
- Chalking and crazing of the insulator’s surface, which resulted in increased contaminant collection, arcing, and flashover.
- Reduction of contamination flashover strength and subsequent increased contamination-induced flashover.
- Deterioration of mechanical strength, which resulted in confusion in the selection of mechanical line loading.
- Loosening of end fittings.
- Bonding failures and breakdowns along the rod-shed interface.
- Water penetration followed by electrical failure.

As a consequence of reported failures, an extensive research effort led to second- and third-generation nonceramic transmission line insulators. These improved units have tracking free sheds, better corona resistance, and slip-free end fittings. A better understanding of failure mechanisms and of mechanical strength-time dependency has resulted in newly designed insulators that are expected to last 20–30 years [8,9]. Increased production quality control and automated manufacturing technology has further improved the quality of these third-generation nonceramic transmission line insulators.



FIGURE 10.8 Post insulators.

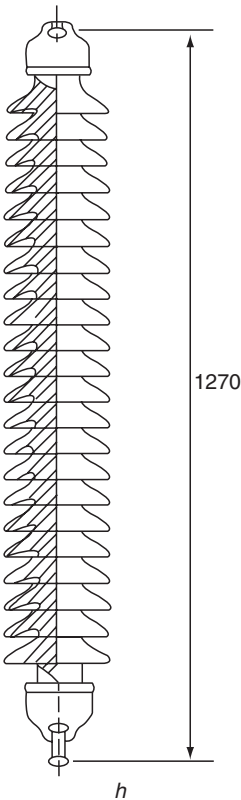


FIGURE 10.9 Long rod insulator.

10.3.1 Composite Suspension Insulators

A cross-section of a third-generation composite insulators is shown in Fig. 10.10. The major components of a composite insulator are:

- End fittings
- Corona ring(s)
- Fiberglass-reinforced plastic rod
- Interface between shed and sleeve
- Weather shed

10.3.1.1 End Fittings

End fittings connect the insulator to a tower or conductor. It is a heavy metal tube with an oval eye, socket, ball, tongue, and a clevis ending. The tube is attached to a fiberglass rod. The duty of the end fitting is to provide a reliable, non-slip attachment without localized stress in the fiberglass rod. Different manufacturers use different technologies. Some methods are:

1. The ductile galvanized iron-end fitting is wedged and glued with epoxy to the rod.
2. The galvanized forged steel-end fitting is swaged and compressed to the rod.
3. The malleable cast iron, galvanized forged steel, or aluminous bronze-end fitting is attached to the rod by controlled swaging. The material is selected according to the corrosion resistance requirement. The end fitting coupling zone serves as a mechanical fuse and determines the strength of the insulator.
4. High-grade forged steel or ductile iron is crimped to the rod with circumferential compression.

The interface between the end fitting and the shed material must be sealed to avoid water penetration. Another technique, used mostly in distribution insulators, involves the weather shed overlapping the end fitting.

10.3.1.2 Corona Ring(s)

Electrical field distribution along a nonceramic insulator is nonlinear and produces very high electric fields near the end of the insulator. High fields generate corona and surface discharges, which are the source of insulator aging. Above 230 kV, each manufacturer recommends aluminum corona rings be installed at the line end of the insulator. Corona rings are used at both ends at higher voltages (>500 kV).

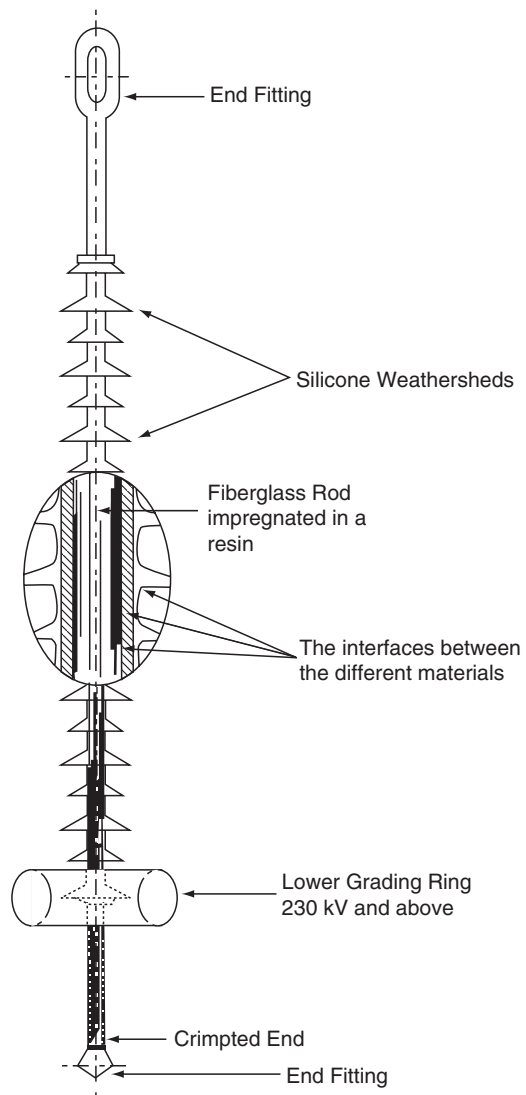


FIGURE 10.10 Cross-section of a typical composite insulator. (From *Toughened Glass Insulators*. Sediver, Inc., Nanterre Cedex, France. With permission.)

10.3.1.3 Fiberglass-Reinforced Plastic Rod

The fiberglass is bound with epoxy or polyester resin. Epoxy produces better-quality rods but polyester is less expensive. The rods are manufactured in a continuous process or in a batch mode, producing the required length. The even distribution of the glass fibers assures equal loading, and the uniform impregnation assures good bonding between the fibers and the resin. To improve quality, some manufacturers use E-glass to avoid brittle fractures. Brittle fracture can cause sudden shattering of the rod.

10.3.1.4 Interfaces Between Shed and Fiberglass Rod

Interfaces between the fiberglass rod and weather shed should have no voids. This requires an appropriate interface material that assures bonding of the fiberglass rod and weather shed. The most frequently used techniques are:

1. The fiberglass rod is primed by an appropriate material to assure the bonding of the sheds.
2. Silicon rubber or ethylene propylene diene monomer (EPDM) sheets are extruded onto the fiberglass rod, forming a tube-like protective covering.
3. The gap between the rod and the weather shed is filled with silicon grease, which eliminates voids.

10.3.1.5 Weather Shed

All high-voltage insulators use rubber weather sheds installed on fiberglass rods. The interface between the weather shed, fiberglass rod, and the end fittings are carefully sealed to prevent water penetration. The most serious insulator failure is caused by water penetration to the interface.

The most frequently used weather shed technologies are:

1. Ethylene propylene copolymer (EPM) and silicon rubber alloys, where hydrated-alumina fillers are injected into a mold and cured to form the weather sheds. The sheds are threaded to the fiberglass rod under vacuum. The inner surface of the weather shed is equipped with O-ring type grooves filled with silicon grease that seals the rod-shed interface. The gap between the end-fittings and the sheds is sealed by axial pressure. The continuous slow leaking of the silicon at the weather shed junctions prevents water penetration.
2. High-temperature vulcanized silicon rubber (HTV) sleeves are extruded on the fiberglass surface to form an interface. The silicon rubber weather sheds are injection-molded under pressure and placed onto the sleeved rod at a predetermined distance. The complete subassembly is vulcanized at high temperatures in an oven. This technology permits the variation of the distance between the sheds.
3. The sheds are directly injection-molded under high pressure and high temperature onto the primed rod assembly. This assures simultaneous bonding to both the rod and the end-fittings. Both EPDM and silicon rubber are used. This one-piece molding assures reliable sealing against moisture penetration.
4. One piece of silicon or EPDM rubber shed is molded directly to the fiberglass rod. The rubber contains fillers and additive agents to prevent tracking and erosion.

10.3.2 Composite Post Insulators

The construction and manufacturing method of post insulators is similar to that of suspension insulators. The major difference is in the end fittings and the use of a larger diameter fiberglass rod. The latter is necessary because bending is the major load on these insulators. The insulators are flexible, which permits bending in case of sudden overload. A typical post-type insulator used for 69-kV lines is shown in [Fig. 10.11](#).

Post-type insulators are frequently used on transmission lines. Development of station-type post insulators has just begun. The major problem is the fabrication of high strength, large diameter fiberglass tubes and sealing of the weather shed.

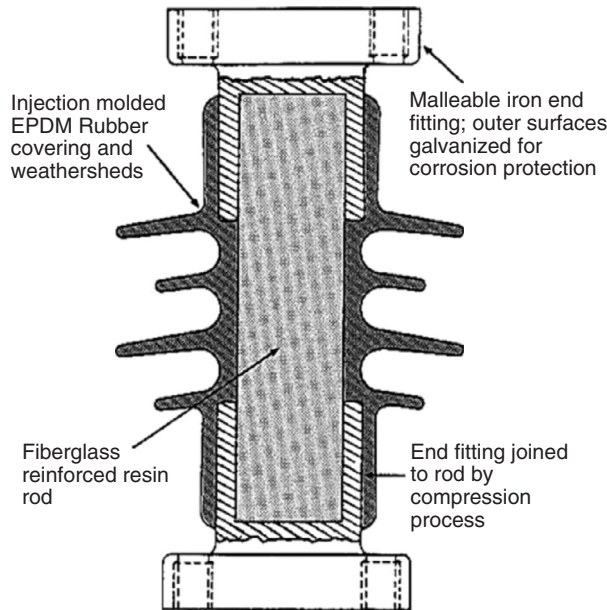


FIGURE 10.11 Post-type composite insulator. (From *Toughened Glass Insulators*. Sediver, Inc., Nanterre Cedex, France. With permission.)

10.4 Insulator Failure Mechanism

10.4.1 Porcelain Insulators

Cap-and-pin porcelain insulators are occasionally destroyed by direct lightning strikes, which generate a very steep wave front. Steep-front waves break down the porcelain in the cap, cracking the porcelain. The penetration of moisture results in leakage currents and short circuits of the unit.

Mechanical failures also crack the insulator and produce short circuits. The most common cause is water absorption by the Portland cement used to attach the cap to the porcelain. Water absorption expands the cement, which in turn cracks the porcelain. This reduces the mechanical strength, which may cause separation and line dropping.

Short circuits of the units in an insulator string reduce the electrical strength of the string, which may cause flashover in polluted conditions.

Glass insulators use alumina cement, which reduces water penetration and the head-cracking problem. A great impact, such as a bullet, can shatter the shell, but will not reduce the mechanical strength of the unit.

The major problem with the porcelain insulators is pollution, which may reduce the flashover voltage under the rated voltages. Fortunately, most areas of the U.S. are lightly polluted. However, some areas with heavy pollution experience flashover regularly.

10.4.2 Insulator Pollution

Insulation pollution is a major cause of flashovers and of long-term service interruptions. Lightning-caused flashovers produce short circuits. The short circuit current is interrupted by the circuit breaker and the line is reclosed successfully. The line cannot be successfully reclosed after pollution-caused flashover because the contamination reduces the insulation's strength for a long time. Actually, the insulator must dry before the line can be reclosed.

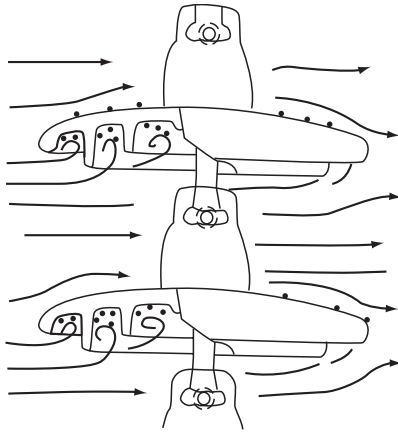


FIGURE 10.12 Deposit accumulation. (From *Application Guide for Composite Suspension Insulators*. Sediver, Inc., York, SC, 1993. With permission.)

the insulator forms a well-dispersed layer and stabilizes around an average value after longer exposure times. However, this average value varies with the changing of the seasons.

Fog, dew, mist, or light rain wets the pollution deposits and forms a conductive layer. Wetting is dependent upon the amount of dissolvable salt in the contaminant, the nature of the insoluble material, duration of wetting, surface conditions, and the temperature difference between the insulator and its surroundings. At night, the insulators cool down with the low night temperatures. In the early morning, the air temperature begins increasing, but the insulator's temperature remains constant. The temperature difference accelerates water condensation on the insulator's surface. Wetting of the contamination layer starts leakage currents.

Leakage current density depends upon the shape of the insulator's surface. Generally, the highest current density is around the pin. The current heats the conductive layer and evaporates the water at the areas with high current density. This leads to the development of dry bands around the pin. The dry bands modify the voltage distribution along the surface. Because of the high resistance of the dry bands, it is across them that most of the voltages will appear. The high voltage produces local arcing. Short arcs (Fig. 10.13) will bridge the dry bands.

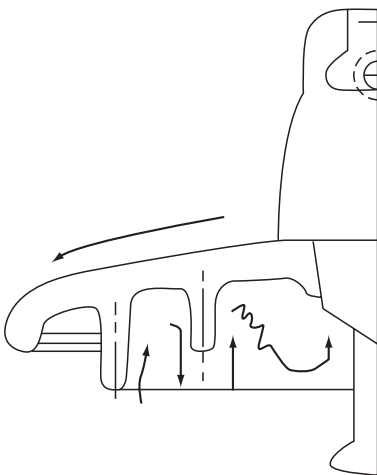


FIGURE 10.13 Dry-band arcing. (From *Application Guide for Composite Suspension Insulators*. Sediver, Inc., York, SC, 1993. With permission.)

10.4.2.1 Ceramic Insulators

Pollution-caused flashover is an involved process that begins with the pollution source. Some sources of pollution are: salt spray from an ocean, salt deposits in the winter, dust and rubber particles during the summer from highways and desert sand, industrial emissions, engine exhaust, fertilizer deposits, and generating station emissions. Contaminated particles are carried in the wind and deposited on the insulator's surface. The speed of accumulation is dependent upon wind speed, line orientation, particle size, material, and insulator shape. Most of the deposits lodge between the insulator's ribs and behind the cap because of turbulence in the airflow in these areas (Fig. 10.12).

The deposition is continuous, but is interrupted by occasional rain. Rain washes the pollution away and high winds clean the insulators. The top surface is cleaned more than the ribbed bottom. The horizontal and V strings are cleaned better by the rain than the I strings. The deposit on

Leakage current flow will be determined by the voltage drop of the arcs and by the resistance of the wet layer in series with the dry bands. The arc length may increase or decrease, depending on the layer resistance. Because of the large layer resistance, the arc first extinguishes, but further wetting reduces the resistance, which leads to increases in arc length. In adverse conditions, the level of contamination is high and the layer resistance becomes low because of intensive wetting. After several arcing periods, the length of the dry band will increase and the arc will extend across the insulator. This contamination causes flashover.

In favorable conditions when the level of contamination is low, layer resistance is high and arcing continues until the

sun or wind dries the layer and stops the arcing. Continuous arcing is harmless for ceramic insulators, but it ages nonceramic and composite insulators.

The mechanism described above shows that heavy contamination and wetting may cause insulator flashover and service interruptions. Contamination in dry conditions is harmless. Light contamination and wetting causes surface arcing and aging of nonceramic insulators.

10.4.2.2 Nonceramic Insulators

Nonceramic insulators have a dirt and water repellent (hydrophobic) surface that reduces pollution accumulation and wetting. The different surface properties slightly modify the flashover mechanism.

Contamination buildup is similar to that in porcelain insulators. However, nonceramic insulators tend to collect less pollution than ceramic insulators. The difference is that in a composite insulator, the diffusion of low-molecular-weight silicone oil covers the pollution layer after a few hours. Therefore, the pollution layer will be a mixture of the deposit (dust, salt) and silicone oil. A thin layer of silicone oil, which provides a hydrophobic surface, will also cover this surface.

Wetting produces droplets on the insulator's hydrophobic surface. Water slowly migrates to the pollution and partially dissolves the salt in the contamination. This process generates high resistivity in the wet region. The connection of these regions starts leakage current. The leakage current dries the surface and increases surface resistance. The increase of surface resistance is particularly strong on the shaft of the insulator where the current density is higher.

Electrical fields between the wet regions increase. These high electrical fields produce spot discharges on the insulator's surface. The strongest discharge can be observed at the shaft of the insulator. This discharge reduces hydrophobicity, which results in an increase of wet regions and an intensification of the discharge. At this stage, dry bands are formed at the shed region. In adverse conditions, this phenomenon leads to flashover. However, most cases of continuous arcing develop as the wet and dry regions move on the surface.

The presented flashover mechanism indicates that surface wetting is less intensive in nonceramic insulators. Partial wetting results in higher surface resistivity, which in turn leads to significantly higher flashover voltage. However, continuous arcing generates local hot spots, which cause aging of the insulators.

10.4.3 Effects of Pollution

The flashover mechanism indicates that pollution reduces flashover voltage. The severity of flashover voltage reduction is shown in [Fig. 10.14](#). This figure shows the surface electrical stress (field), which causes flashover as a function of contamination, assuming that the insulators are wet. This means that the salt in the deposit is completely dissolved. The Equivalent Salt Deposit Density (ESDD) describes the level of contamination.

These results show that the electrical stress, which causes flashover, decreases by increasing the level of pollution on all of the insulators. This figure also shows that nonceramic insulator performance is better than ceramic insulator performance. The comparison between EPDM and silicone shows that flashover performance is better for the latter.

[Table 10.6](#) shows the number of standard insulators required in contaminated areas. This table can be used to select the number of insulators, if the level of contamination is known.

Pollution and wetting cause surface discharge arcing, which is harmless on ceramic insulators, but produces aging on composite insulators. Aging is a major problem and will be discussed in the next section.

10.4.4 Composite Insulators

The Electric Power Research Institute (EPRI) conducted a survey analyzing the cause of composite insulator failures and operating conditions. The survey was based on the statistical evaluation of failures reported by utilities.

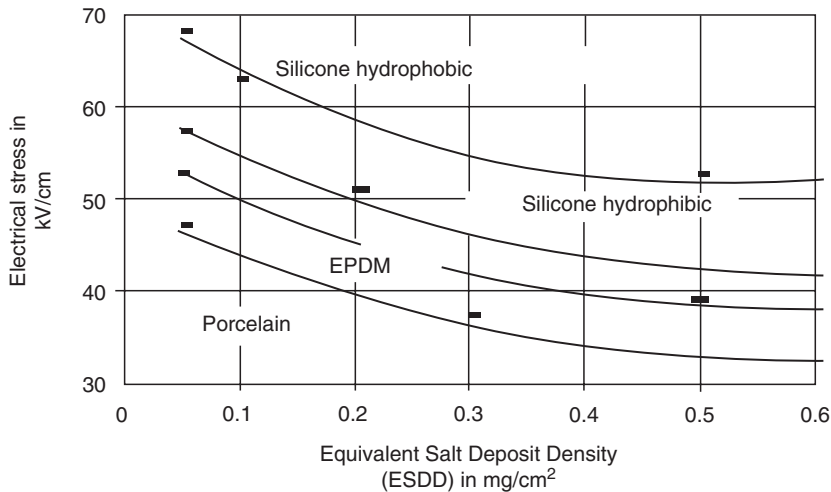


FIGURE 10.14 Surface electrical stress vs. ESDD of fully wetted insulators (laboratory test results). (From *Application Guide for Composite Suspension Insulators*. Sediver, Inc., York, SC, 1993. With permission.)

Results show that a majority of insulators (48%) are subjected to very light pollution and only 7% operate in heavily polluted environments. Figure 10.15 shows the typical cause of composite insulator failures. The majority of failures are caused by deterioration and aging. Most electrical failures are caused by water penetration at the interface, which produces slow tracking in the fiberglass rod surface. This tracking produces a conduction path along the fiberglass surface and leads to internal breakdown of the insulator. Water penetration starts with corona or erosion-produced cuts, holes on the weather shed, or mechanical load-caused separation of the end-fitting and weather shed interface.

Most of the mechanical failures are caused by breakage of the fiberglass rods in the end fitting. This occurs because of local stresses caused by inappropriate crimping. Another cause of mechanical failures is brittle fracture. Brittle fracture is initiated by the penetration of water containing slight acid from pollution. The acid may be produced by electrical discharge and acts as a catalyzer, attacking the bonds and the glass fibers to produce a smooth fracture. The brittle fractures start at high mechanical stress points, many times in the end fitting.

10.4.5 Aging of Composite Insulators

Most technical work concentrates on the aging of nonceramic insulators and the development of test methods that simulate the aging process. Transmission lines operate in a polluted atmosphere.

TABLE 10.6 Number of Standard Insulators for Contaminated Areas

System Voltage KV	Level of Contamination			
	Very light	Light	Moderate	Heavy
138	6/6	8/7	9/7	11/8
230	11/10	14/12	16/13	19/15
345	16/15	21/17	24/19	29/22
500	25/22	32/27	37/29	44/33
765	36/32	47/39	53/42	64/48

Note: First number is for I-string; second number is for V-string.

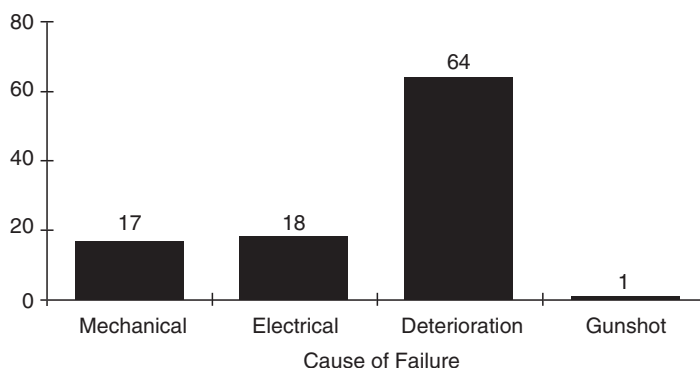


FIGURE 10.15 Cause of composite insulator failure. (From Schneider et al., Nonceramic insulators for transmission lines, *IEEE Transaction on Power Delivery*, 4(4), 2214–2221, April, 1989.)

Inevitably, insulators will become polluted after several months in operation. Fog and dew cause wetting and produce uneven voltage distribution, which results in surface discharge. Observations of transmission lines at night by a light magnifier show that surface discharge occurs in nearly every line in wet conditions. UV radiation and surface discharge cause some level of deterioration after long-term operation. These are the major causes of aging in composite insulators which also lead to the uncertainty of an insulator's life span. If the deterioration process is slow, the insulator can perform well for a long period of time. This is true of most locations in the U.S. and Canada. However, in areas closer to the ocean or areas polluted by industry, deterioration may be accelerated and insulator failure may occur after a few years of exposure [10,11]. Surveys indicate that some insulators operate well for 18–20 years and others fail after a few months. An analysis of laboratory data and literature surveys permit the formulation of the following aging hypothesis:

1. Wind drives dust and other pollutants into the composite insulator's water-repellent surface. The combined effects of mechanical forces and UV radiation produces slight erosion of the surface, increasing surface roughness and permitting the slow buildup of contamination.
2. Diffusion drives polymers out of the bulk skirt material and embeds the contamination. A thin layer of polymer will cover the contamination, assuring that the surface maintains hydrophobicity.
3. High humidity, fog, dew, or light rain produce droplets on the hydrophobic insulator surface. Droplets may roll down from steeper areas. In other areas, contaminants diffuse through the thin polymer layer and droplets become conductive.
4. Contamination between the droplets is wetted slowly by the migration of water into the dry contaminant. This generates a high resistance layer and changes the leakage current from capacitive to resistive.
5. The uneven distribution and wetting of the contaminant produces an uneven voltage stress distribution along the surface. Corona discharge starts around the droplets at the high stress areas. Additional discharge may occur between the droplets.
6. The discharge consumes the thin polymer layer around the droplets and destroys hydrophobicity.
7. The deterioration of surface hydrophobicity results in dispersion of droplets and the formation of a continuous conductive layer in the high stress areas. This increases leakage current.
8. Leakage current produces heating, which initiates local dry band formation.
9. At this stage, the surface consists of dry regions, highly resistant conducting surfaces, and hydrophobic surfaces with conducting droplets. The voltage stress distribution will be uneven on this surface.

10. Uneven voltage distribution produces arcing and discharges between the different dry bands. These cause further surface deterioration, loss of hydrophobicity, and the extension of the dry areas.
11. Discharge and local arcing produces surface erosion, which ages the insulator's surface.
12. A change in the weather, such as the sun rising, reduces the wetting. As the insulator dries, the discharge diminishes.
13. The insulator will regain hydrophobicity if the discharge-free dry period is long enough. Typically, silicon rubber insulators require 6–8 h; EPDM insulators require 12–15 h to regain hydrophobicity.
14. Repetition of the described procedure produces erosion on the surface. Surface roughness increases and contamination accumulation accelerates aging.
15. Erosion is due to discharge-initiated chemical reactions and a rise in local temperature. Surface temperature measurements, by temperature indicating point, show local hot-spot temperatures between 260°C and 400°C during heavy discharge.

The presented hypothesis is supported by the observation that the insulator life spans in dry areas are longer than in areas with a wetter climate. Increasing contamination levels reduce an insulator's life span. The hypothesis is also supported by observed beneficial effects of corona rings on insulator life.

DeTourreil et al. (1990) reported that aging reduces the insulator's contamination flashover voltage. Different types of insulators were exposed to light natural contamination for 36–42 months at two different sites. The flashover voltage of these insulators was measured using the "quick flashover salt fog" technique, before and after the natural aging. The quick flashover salt fog procedure subjects the insulators to salt fog (80 kg/m³ salinity). The insulators are energized and flashed over 5–10 times. Flashover was obtained by increasing the voltage in 3% steps every 5 min from 90% of the estimated flashover value until flashover. The insulators were washed, without scrubbing, before the salt fog test. The results show that flashover voltage on the new insulators was around 210 kV and the aged insulators flashed over around 184–188 kV. The few years of exposure to light contamination caused a 10–15% reduction of salt fog flashover voltage.

Natural aging and a follow-up laboratory investigation indicated significant differences between the performance of insulators made by different manufacturers. Natural aging caused severe damage on some insulators and no damage at all on others.

10.5 Methods for Improving Insulator Performance

Contamination caused flashovers produce frequent outages in severely contaminated areas. Lines closer to the ocean are in more danger of becoming contaminated. Several countermeasures have been proposed to improve insulator performance. The most frequently used methods are:

1. **Increasing leakage distance by increasing the number of units or by using fog-type insulators.** The disadvantages of the larger number of insulators are that both the polluted and the impulse flashover voltages increase. The latter jeopardizes the effectiveness of insulation coordination because of the increased strike distance, which increases the overvoltages at substations.
2. **Application insulators are covered with a semiconducting glaze.** A constant leakage current flows through the semiconducting glaze. This current heats the insulator's surface and reduces the moisture of the pollution. In addition, the resistive glaze provides an alternative path when dry bands are formed. The glaze shunts the dry bands and reduces or eliminates surface arcing. The resistive glaze is exceptionally effective near the ocean.
3. **Periodic washing of the insulators with high-pressure water.** The transmission lines are washed by a large truck carrying water and pumping equipment. Trained personnel wash the insulators by aiming the water spray toward the strings. Substations are equipped with permanent washing systems. High-pressure nozzles are attached to the towers and water is supplied from a central pumping station. Safe washing requires spraying large amounts of water at the insulators in a

short period of time. Fast washing prevents the formation of dry bands and pollution-caused flashover. However, major drawbacks of this method include high installation and operational costs.

4. **Periodic cleaning of the insulators by high pressure driven abrasive material, such as ground corn cobs or walnut shells.** This method provides effective cleaning, but cleaning of the residual from the ground is expensive and environmentally undesirable.
5. **Replacement of porcelain insulators with nonceramic insulators.** Nonceramic insulators have better pollution performance, which eliminates short-term pollution problems at most sites. However, insulator aging may affect the long-term performance.
6. **Covering the insulators with a thin layer of room-temperature vulcanized (RTV) silicon rubber coating.** This coating has a hydrophobic and dirt-repellent surface, with pollution performance similar to nonceramic insulators. Aging causes erosion damage to the thin layer after 5–10 years of operation. When damage occurs, it requires surface cleaning and a reapplication of the coating. Cleaning by hand is very labor intensive. The most advanced method is cleaning with high pressure driven abrasive materials like ground corn cobs or walnut shells. The coating is sprayed on the surface using standard painting techniques.
7. **Covering the insulators with a thin layer of petroleum or silicon grease.** Grease provides a hydrophobic surface and absorbs the pollution particles. After one or two years of operation, the grease saturates the particles and it must be replaced. This requires cleaning of the insulator and application of the grease, both by hand. Because of the high cost and short life span of the grease, it is not used anymore.

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